Snake River Oil and Gas, LLC

117 East Calhoun – P.O. Box 500

Magnolia, Arkansas 71753

April 27, 2021

DELIVERED BY ELECTRONIC-MAIL

Ms. Karen Burgess, Manager
Groundwater and Drinking Water Section
United States Environmental Protection Agency – Region 10
Water Division
1200 Sixth Avenue, Suite 155
Seattle, WA 98101-3188

Re: Underground Injection Control (UIC) Permit Application No. ID-2D001-A – Request for a Revised Monitoring Plan

Dear Ms. Burgess:

This letter transmits Snake River Oil and Gas, LLC's response to your April 5, 2021 letter requesting a revised monitoring plan.

We have revised the subject permit's monitoring plan (Attachment P in the plan) and are submitting it for your review as Attachment I. This monitoring plan addresses the concerns in your letter by:

1) Confirming objectively the confinement of the faults bounding the proposed injection reservoir prior to injection. The plan calls for measuring the static reservoir pressures in the proposed injection and neighboring fault blocks, prior to the initiation of injection, so that confirmation of fault sealing may be determined. It is expected that upon perforating and pressure testing the proposed injection sands in the DJS #2-14 Well that they will be found to be at virgin pressure. It is further expected that the static reservoir pressures measured in the offset wells in the adjacent fault blocks will be significantly less than virgin pressure. If this result is obtained, the sealing competency of the bounding faults will be objectively shown, prior to initiation of injection.

2) Monitoring fluid movement and reservoir pressures during the life of the injection well. The plan utilizes initial and subsequent annual pressure fall-off test transient analyses of the proposed injection well (DJS 2-14). This will provide the best estimate of initial and subsequent average reservoir pressures in the injection reservoir and thus confirm the reservoir boundaries

documented by the 3-D seismic data. These reservoir pressures and cumulative injection volumes will be compared with the predicted confined reservoir relationship to show that the injection reservoir volume is bounded and contained during the service life of the injection well.

We have done modelling to address expected fluid movement within the reservoir during the service life of the well. We include 2 cases, an expected maximum Area of Emplacement (AOE) and an expected AOE after a hypothetical first year of injection service. This shows that the area occupied by injection water would be relatively small, compared to the area of Fault Block E. The models are in Attachment III and are submitted as a revision of the prior Attachment H-1 of the Permit Application (Calculation of Confined Injection Zone Capacity). We have not altered the calculations but have simply added the models and maps that show the expected AOE's for the cases considered.

In addition, we are submitting a revised wellbore completion plan to include perforating in each of the Willow Sands to allow for injection over the entire permitted interval. This is intended to allow for hydraulic connection with the entire permeable reservoir pore space and provide for a more uniform pressure and area of injectate emplacement in the reservoir. Attachment II includes the revised Attachments L, M-5, Q-1, Q-2, and Q-3, reflecting the revised perforation intervals.

Included for reference is Attachment IV, a copy of your 4/5/2021 letter.

Please let us know if additional information is needed or if you have any questions.

Thank you for your efforts and help in this matter.

Sincerely,

Mr. Richard Brown
Manager
Snake River Oil and Gas, LLC

Attachments:

1. Attachment I – UIC Permit Application Attachment P (revised 4/272021)
2. Attachment II –
    a. Log Section Illustrating Proposed Perforations – Sands 3 and 4
    b. Log Section Illustrating Proposed Perforations – Sands 5 and 6
    c. UIC Permit Application Attachment L (revised 4/27/2021)
    d. UIC Permit Application Attachment M-5 (revised 4/27/2021)
    e. UIC Permit Application Attachment Q-1 (revised 4/27/2021)
    f. UIC Permit Application Attachment Q-2 (revised 4/27/2021)
    g. UIC Permit Application Attachment Q-3 (revised 4/27/2021)
3. Attachment III – Attachment H-1 Injection Capacity with Area of Encroachment Exhibit (revised 4/27/2021)
4. Attachment IV – EPA Letter of 4/5/2021

Attachment I

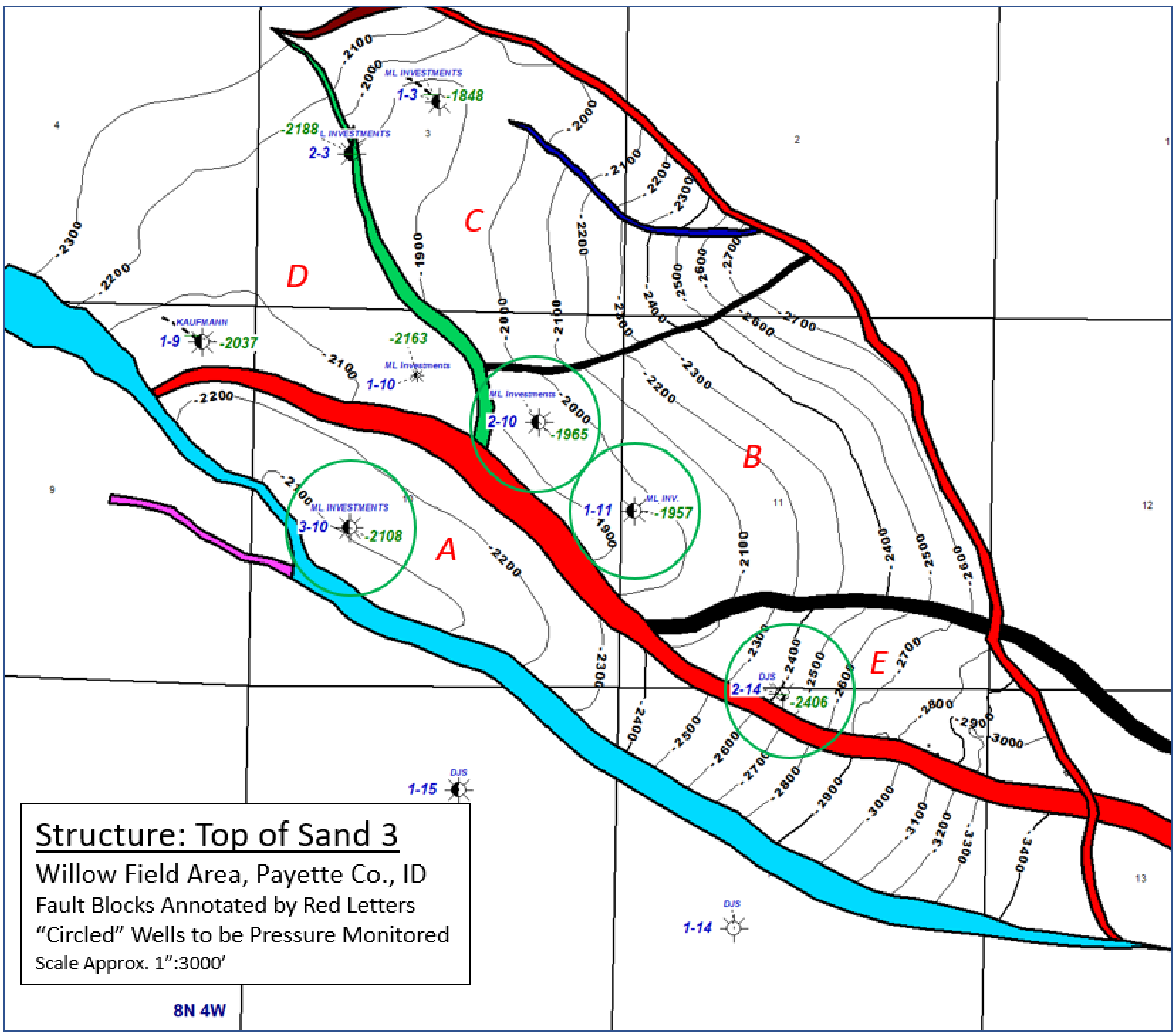
UIC Permit Application Attachment P (revised 4/27/2021)

ATTACHMENT P: Monitoring Program

A monitoring program will be implemented for the injection system in order to maintain the integrity of the entire system and injection into the permitted interval/ volume in Fault Block E prior to and during the service life of the injection well.

1. Offset Fault Block / Well Testing Prior to Beginning Injection:
   a. To confirm that Fault Block E is currently not in hydraulic communication with Fault Block A and Fault Block B, average reservoir pressures will be measured in each fault block before beginning injection. (Refer to Figure P-1 below for a map that shows the fault blocks and wells.) Both Fault Block B and A have experienced production and consequent pressure reductions, while Fault Block E has not produced and should be at virgin reservoir pressure.

Figure P-1



i. Work plans for these data collection operations will be submitted to the EPA for review and approval before execution of the work.

ii. Strategy by fault block / well / status:

1) Fault Block E / DJS 2-14 / injection well before beginning injection: Static bottom hole pressure will be measured using wireline conveyed downhole pressure gauges in the DJS 2-14 Well after the well has been completed for injection service. This pressure should be the virgin pressure in this fault block and should be approximately the same as other virgin pressures observed in this area. This has been approximately equal to a fresh-water gradient, or approximately 0.43 psi/ft.

2) Fault Blocks A and B / ML Investments 3-10 and ML Investments 2-10 / producing wells: In these fault blocks, adjacent to Fault Block E, pressure build-up transient pressure tests (PBUT) will be utilized in the producing wells ML Investments 2-10, and the ML Investments 3-10. Wireline conveyed pressure gauges will collect producing bottom hole pressure and build-up pressure after the wells are shut-in. Surface pressure will also be monitored and utilized to determine the required shut-in time to allow for analysis to determine average reservoir pressures. These pressures are expected to be well below the original reservoir pressures, which were originally equivalent to a fresh water gradient.

3) Fault Block B – ML Investments 1-11 / shut-in well: For the non-producing ML Investments 1-11 well in Fault Block B, a static bottom hole pressure will be measured (consisting of a gradient survey in the tubing and a 30-minute stop station at the bottom of the tubing) at the completion of the PBUT in its neighboring well, the ML Investments 2-10. This pressure should be very close to the pressure observed in the ML Investments 2-10, as the 3D Seismic data indicates that they are in the same fault block.

iii. The results of these tests and all data will be analyzed and submitted to the EPA for review and approval. Separation will be shown by comparing the reservoir pressure of the DJS 2-14, in Fault Block E, to each of the reservoir pressures measured in the offset fault blocks (ML Investments 3-10 in Fault Block A, and ML Investments 2-10/ML Investments 1-11 in Fault Block B). The pressure in the DJS 2-14 should be close to a virgin pressure of a fresh water gradient (0.43 psi/ft). In addition, the pressures in each of Fault Blocks B and A should be significantly less than Fault Block E to illustrate there is no communication between the fault blocks. Assuming that Fault Block E is at virgin pressure and separation between Fault Block E and Fault Blocks A and B is apparent, SROG will request approval from the EPA to proceed with injection.

2. Monitoring at the DJS 2-14 (proposed Injection well) and Pump station (facility):
    a. Step-rate tests (SRT's) will be performed at initial completion and after any change in the perforated injection interval, to define the Maximum Surface Injection Pressure (MSIP), and the Limiting Surface Injection Pressure (LSIP). Additional SRT's will be performed at least annually. LSIP will be defined as 50 psi below MSIP.
        i. A work plan for any planned SRT will be submitted to the EPA for review, comment, and approval before implementing the test. SRT procedures will follow the EPA Region 8 - Step Rate Test Procedure (1/12/99), or other EPA reviewed/approved procedures, as directed by EPA Region 10.
        ii. SRT data will be documented with a service company or other acceptable records or charts, and the test should be witnessed by an EPA inspector.
        iii. SRT analysis results report and data will be submitted to the EPA in digital format for review and approval.
        iv. Any MSIP or LSIP reductions resulting from SRT results will be implemented immediately in injection operations, or injection will be halted until rate and pressure control changes can be implemented.
    a. A mechanical integrity test (MIT) will be performed on the DJS 2-14 by pressuring up the tubing/casing annulus to the Maximum Surface Injection Pressure, as determined by the Step Rate Test, and monitoring for any pressure leakoff, with a fail-pass criterion of less than 5% leakoff in 30 minutes. Work plans for any MIT will be submitted to the EPA for review and approval before execution of the plan. An MIT will be performed at the initial completion of the well and every 3 years after the initial MIT. MIT's will also be performed any time the well completion tubing/packer/wellhead is pulled or replaced. SROG will adjust test pressures, timing, leakoff criteria, and test frequency as needed to comply with EPA Region 10 requirements.
    b. Transient Pressure Fall-Off Testing:
        i. Design: A work plan for any planned transient pressure fall-off test (PFOT) will be submitted to the EPA for review, comment, and approval before implementing the test. PFOT procedures will follow the EPA Region 9 – UIC Pressure Falloff Requirements (August 8, 2002), or other EPA reviewed/approved procedure, as directed by EPA Region 10.
        ii. Frequency:
            1) A pressure fall-off test (PFOT) will be run as soon as possible after beginning injection and establishing stabilized rates and operations. It is anticipated that this will occur during the 1st 30 days of the injection operation, assuming that injection operations are stable. This allows for the establishment of a pseudo-steady state pressure profile in the reservoir before the PFOT, which provides support for the analysis results.

2) Annual PFOT's will be performed after the first PFOT, within 12 months of the prior PFOT.

iii. Dual bottomhole pressure recording devices will be employed.

iv. The duration of each PFOT will be long enough to observe a valid pressure fall-off curve and long enough to support persuasive analysis and accurate estimates of permeability, average reservoir pressure, and to support the presence of a bounded reservoir.

v. PFOT analysis results report and data will be submitted to the EPA in digital format for review and approval.

3) To compare reservoir pressure resulting from the PFOT to expected reservoir pressure, as estimated by the Injection Capacity calculation, the report will include a comparison of actual versus expected pressures to illustrate that pressure is increasing with cumulative injection, as expected. This will be included as part of the PFOT analysis results report.

4) As part of the report, the area occupied by the injected fluid will be estimated and presented in a map view. This will be performed using simple bulk volumetrics and using the isopach map and consideration of average reservoir pressure resulting from the PFOT analysis.

c. The total injection system will be monitored to assure integrity and safe operation. SROG's existing SCADA system will be utilized to monitor and record surface rates and surface pressures, generate alarms, and automatically shut down the injection system if control limits are exceeded. Alarms will automatically be sent to operations personnel. See Figure P-2 below for a simple illustration of the injection system.

i. The pumping pressure at the facility that is feeding water to the DJS 2-14 will be monitored, (see Attachment K for detail) and high- and low-pressure alarms/ shut-down triggers will be configured to turn off the pump. These limits will be defined by the lowest pressure limit of the components in the injection system that is installed.

ii. The DJS 2-14 wellhead tubing injection pressure will be monitored. High-pressure and low-pressure alarms / shut-down triggers will be set to turn off the pump. The high-pressure shut-down limit for the tubing will be set to equal the LSIP indicated by SRT results.

iii. The tubing-casing annulus pressure will be monitored – this pressure should remain static at 0 psi (see Attachment K for detail). High-pressure alarms will notify operations personnel if a pressure increase is noted. Note that some variation in this pressure may be seen due to variations in injection fluid temperature over time. Pressure increases will be assessed and pressure due to temperature expansion will be bled off while monitoring fluid volumes required to reduce the pressure back to 0 psi. If there is an indication of a tubing or packer leak, injection operations will immediately be shut down. Details of pressure variations and bleeding operations will be noted and reported within 24 hours to the EPA and also will be included in quarterly and annual reports.

iv. The surface casing pressure will be read and recorded daily by the field operator – this pressure should remain static at 0 psi (see Attachment K for detail). Note that the surface casing has been cemented from the surface, so there is little if any potential of communication with injection fluid or pressure. Similar to the tubing – casing annulus, all pressure increases will be assessed and pressure due to temperature expansion will be bled off while monitoring fluid volumes required to reduce the pressure back to 0 psi. If there is an indication of a tubing or packer leak, injection operations will immediately be shut down. Details of pressure variations and bleeding operations will be noted and reported within 24 hours to the EPA and also will be included in quarterly and annual reports.

v. All monitored pressure transducers/gauges in the system will be inspected and recalibrated/replaced as necessary to ensure accurate readings are being recorded. The frequency of these inspections will occur at least once every quarter and the test results and actions taken will be documented and reported in quarterly and annual reports.

d. The injection flow line will be monitored and tested to maintain integrity:

i. The injection flow line route from the facility to the DJS 2-14 disposal site will be visually inspected to confirm there are no line leaks that have developed. This will occur on a daily basis unless the weather and/or terrain conditions make this impractical or unsafe.

ii. Dual metering at endpoints will allow for indication and alarm of leak events.

iii. The injection flowline will be pressure tested 4 times per year (at least once per quarter), beginning with the initial commissioning of the pipeline system.

1) Each pressure test will be held for a minimum of 1 hour.

2) Maximum test pressure:

a. At initial commissioning, the flowline will be pressured to 80% of the Specified Minimum Yield Strength of the flowline, subject to reduction to the test limits created by any flanges or valves involved in the system test. Initial commissioning pressure will be at least as high as the routine test pressure specified below.

b. Routine hydrotesting for integrity assurance will be governed by the LSIP. The system will be pressured to create a flowline pressure of 150% of the LSIP at the wellhead. The wellbore will be isolated from the test pressure with a block and bleed fitting or valve configuration. (Note: The exact numeric value of the test pressure is as of yet undefined. This pressure will be determined after completion of the DJS 2-14 well as an injector. When the well is completed, the initial step-rate test will be run to determine the exact LSIP of the injector, as the LSIP will be defined as being 50 psi less than the step-rate test parting wellhead pressure (MSIP). This maximum allowable wellhead operating pressure will govern the determination of all other pump discharge and line pressure limits. It should be noted that the pump will be located at the Little Willow Facility, which is approximately 270’ lower, on an elevation basis than the wellhead location of the DJS 2-14. This means the hydrostatic pressure seen at the pump will always be at least approximately 120 psi higher than the pressure seen at the wellhead.)

e. Any abnormalities in the above monitoring criteria will require that injection operations cease immediately. Diagnostics will be performed to determine and rectify the cause of the abnormal situation.

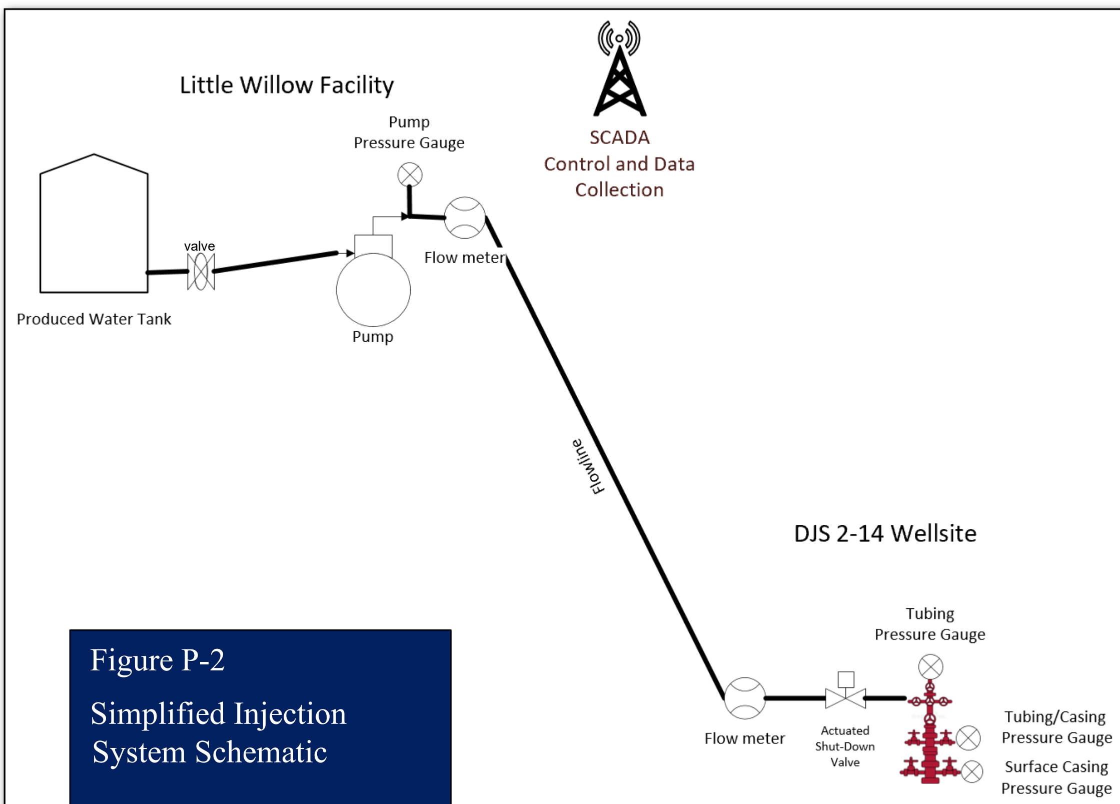


Figure P-2

Simplified Injection System Schematic

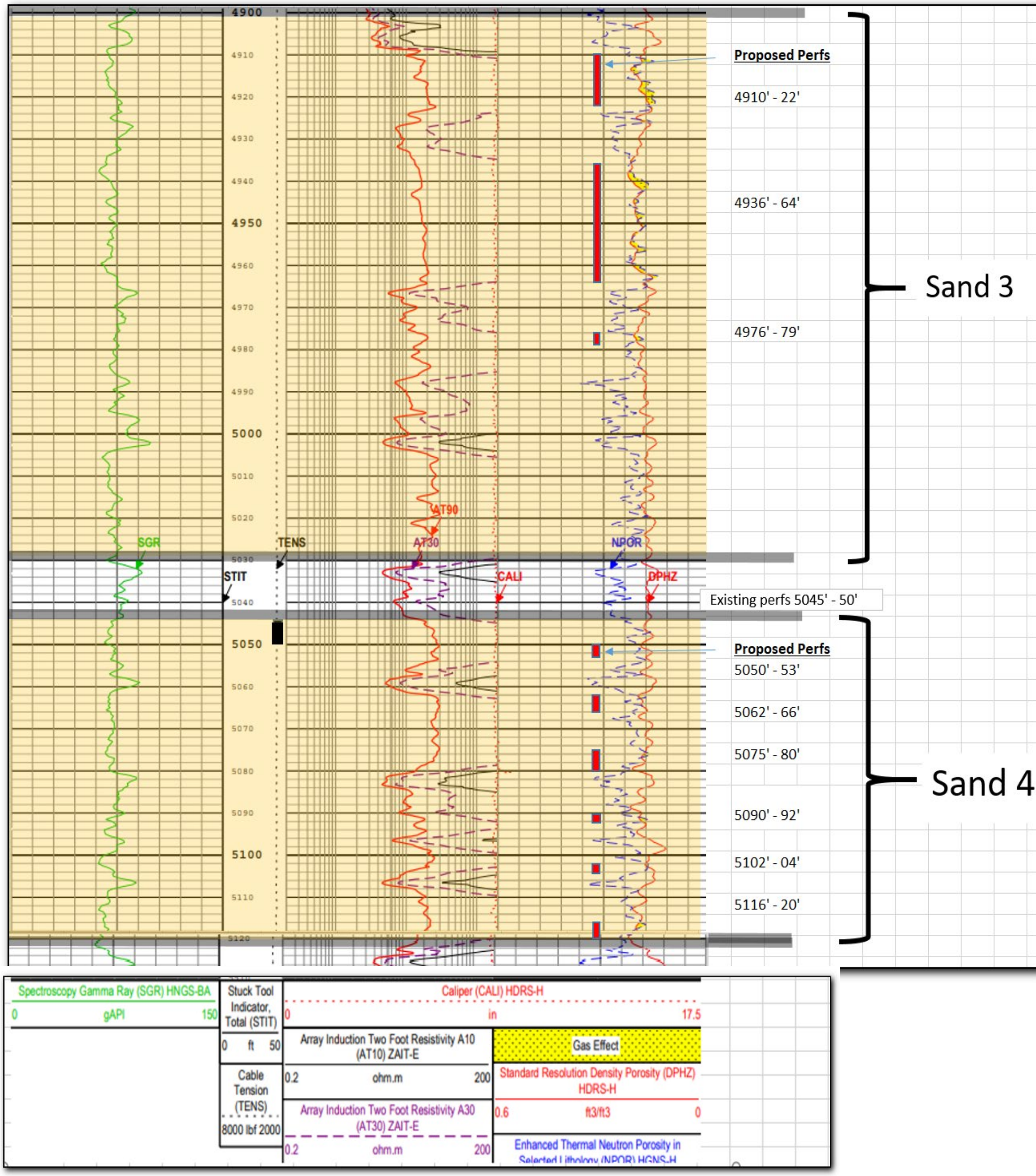
3. <u>Monitoring Reports:</u>
    a. A quarterly report will be generated and filed by the 15th day of the following month.
        i. This report will include all monitored pressures and injection/flow rates, shown as an average for each day and averaged by month. Accumulated injected volumes will also be reported on a daily basis.
        ii. The monthly report will include reports of any work, including:
            1) pressure gauge and flow meter calibrations and repairs,
            2) slickline or other well work,
            3) MIT, SRT, or PFOT work and analysis reports,
            4) facility or significant operational changes,
            5) up and downtime for injection operation for each day,
            6) water sampling and analysis reports,
            7) leak and repair events
    b. An annual report will be generated and filed by the 15th day of the following month.
        i. This report will include an annual summary analysis of the water, representative of the prior year's injection. This analysis will comply with the applicable analytical measurements and methods that have been approved by the EPA. Water analyses will be performed at least annually, and additional analyses will be performed as any changes in water quality dictate, to be able to represent the water injected during the year.
        ii. The annual report will summarize the prior year injection volumes by month, with average rates, wellhead injection pressures, and downtime for each month.
        iii. An updated summary project history of the chronology of work, events, changes, sampling, repairs, modifications, etc. will be included as part of the report.

Attachment II

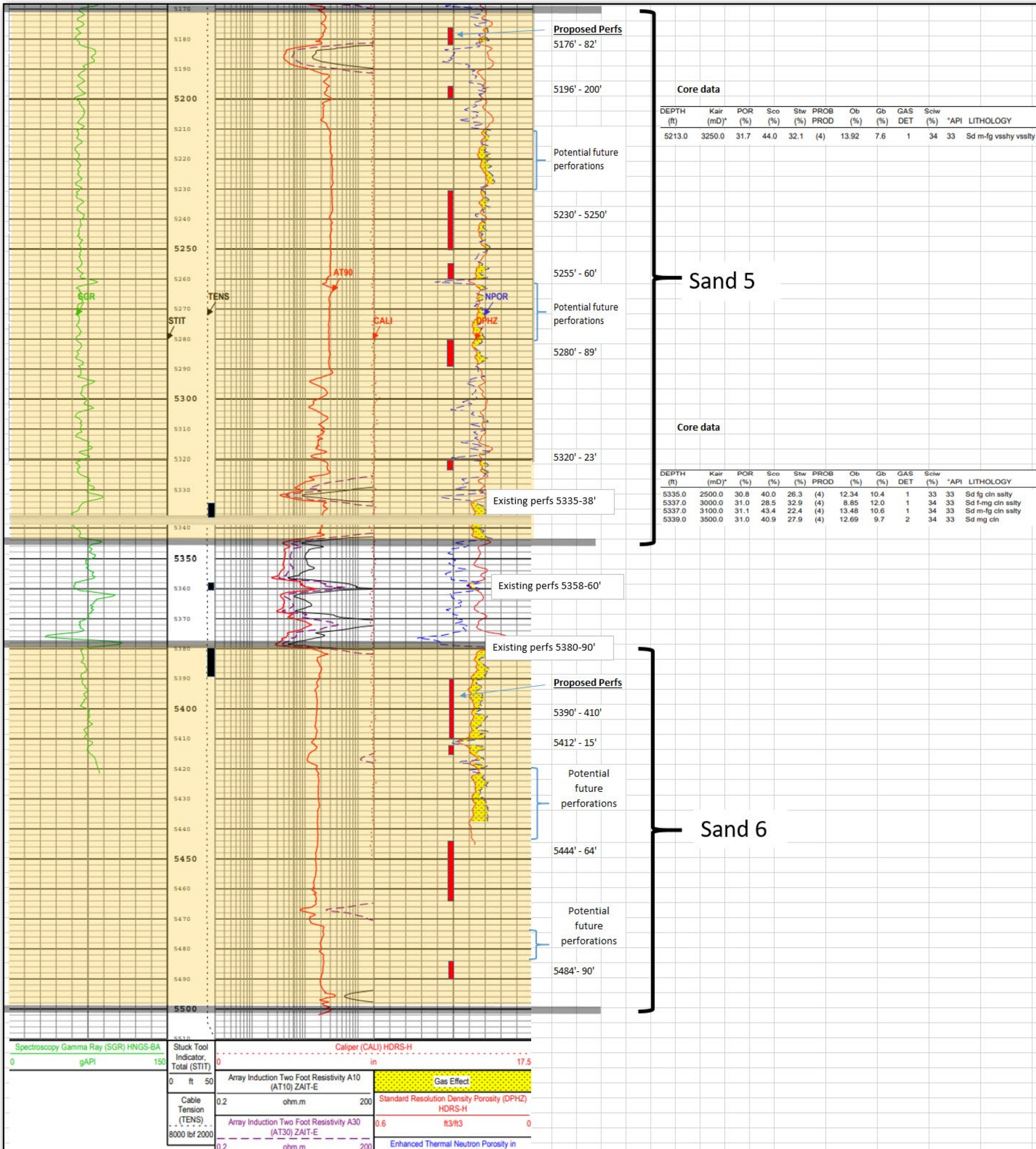
a. Log Section Illustrating Proposed Perforations – Sands 3 and 4
b. Log Section Illustrating Proposed Perforations – Sands 5 and 6
c. UIC Permit Application Attachment L (revised 4/26/2021)
d. UIC Permit Application Attachment M-5 (revised 4/26/2021)
e. UIC Permit Application Attachment Q-1 (revised 4/26/2021)
f. UIC Permit Application Attachment Q-2 (revised 4/26/2021)
g. UIC Permit Application Attachment Q-3 (revised 4/26/2021)

DJS 2-14 Log Section

Proposed Perforations in Sands 3 and 4



DJS 2-14 Log Section
Proposed Perforations in Sands 5 and 6



Core data

DEPTH (ft)	Kair (mD)*	POR (%)	Sco (%)	Stw (%)	PROB PROD	Ob (%)	Gb (%)	GAS DET	Sciw (%)	°API	LITHOLOGY
5213.0	3250.0	31.7	44.0	32.1	(4)	13.92	7.6	1	34	33	Sd m-fg vsshy vsslty

Core data

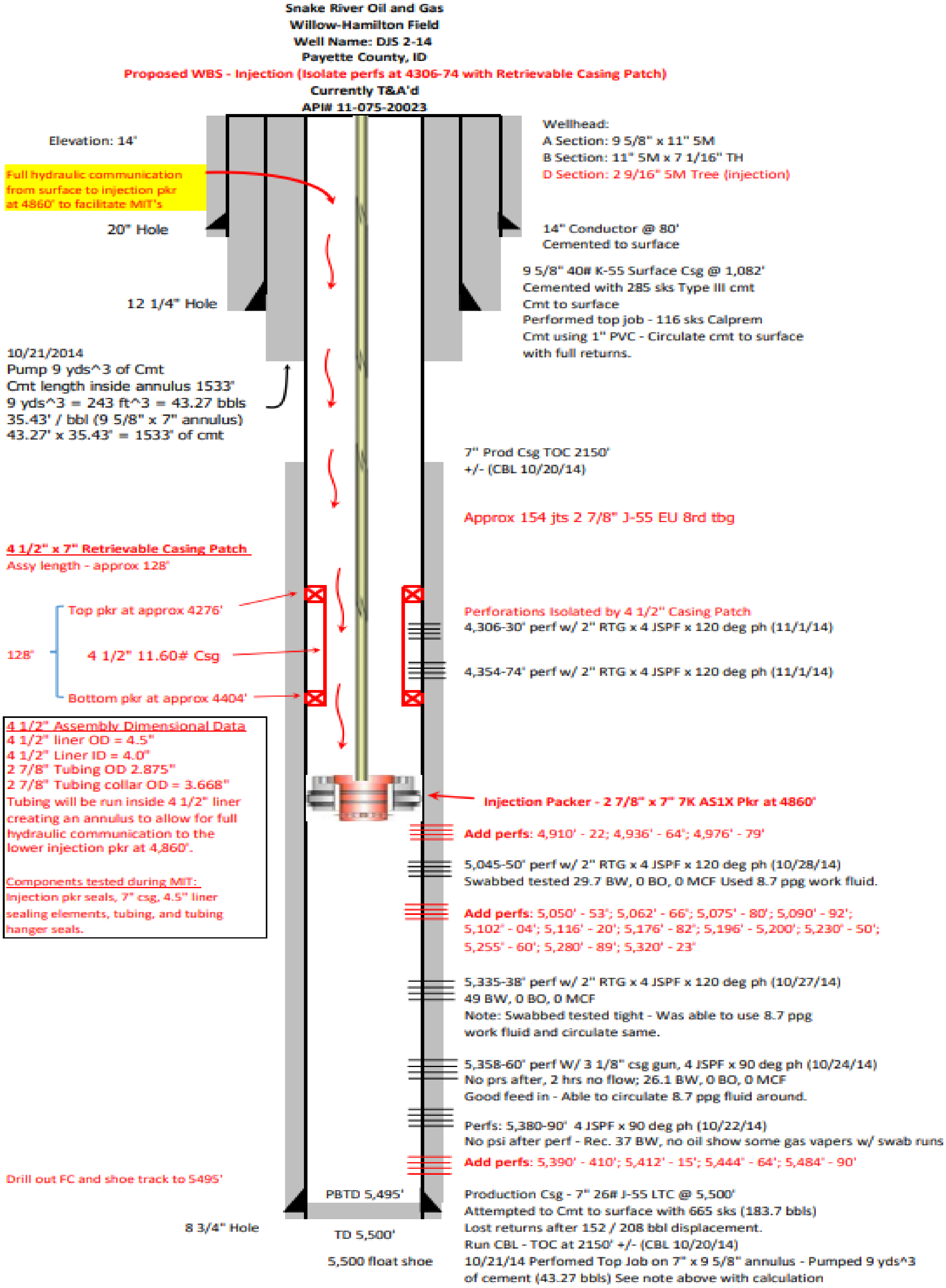
DEPTH (ft)	Kair (mD)*	POR (%)	Sco (%)	Stw (%)	PROB PROD	Ob (%)	Gb (%)	GAS DET	Sciw (%)	°API	LITHOLOGY
5335.0	2500.0	30.8	40.0	26.3	(4)	12.34	10.4	1	33	33	Sd fg cln sslty
5337.0	3000.0	31.0	28.5	32.9	(4)	8.85	12.0	1	34	33	Sd f-mg cln sslty
5337.0	3100.0	31.1	43.4	22.4	(4)	13.48	10.6	1	34	33	Sd m-fg cln sslty
5339.0	3500.0	31.0	40.9	27.9	(4)	12.69	9.7	2	34	33	Sd mg cln

Attachment L – Construction Procedures

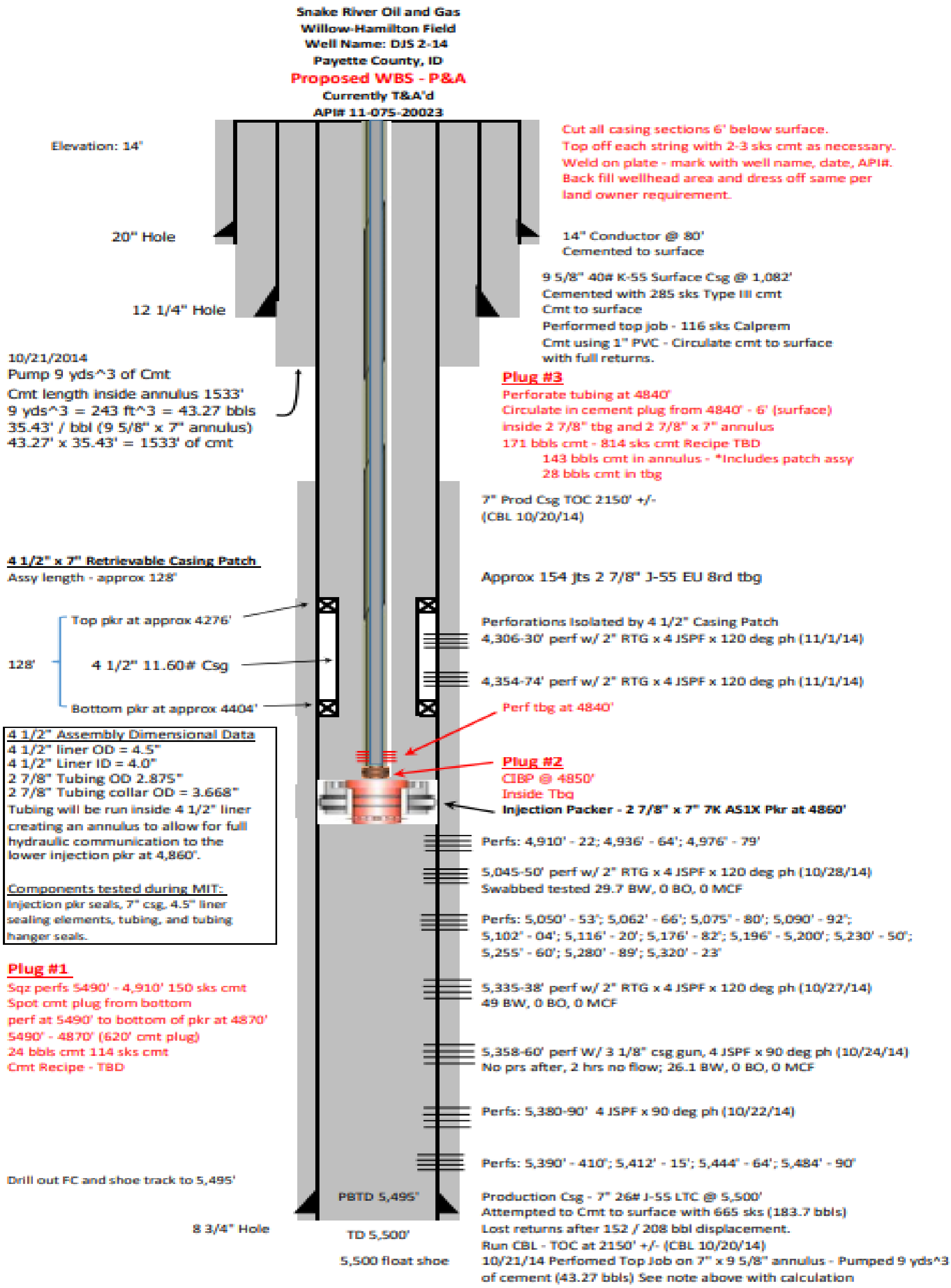
Planned Well Construction Procedure for Injection:

1. Move-in workover rig and rig up same.
2. Pressure test 7” casing above bridge plug at 4,294’.
3. Drill out plugs, cement retainers, and shoe track to 5,495’ (Injection interval 4,910’ – 5,500’).
4. Add perforations:
    a. *Sand 3*
        i. 4,910’ – 4922’; 4,936’ – 4,964’; 4,976’ – 4,979’
    b. *Sand 4*
        i. 5,050’ – 5053’; 5,062’ – 5,066’; 5,075’ – 5,080’; 5,090’ – 5,092’; 5,102’ – 5,104’; 5,116’ – 5,120’
    c. *Sand 5*
        i. 5,176’ – 5,182’; 5,196’ – 5,200’; 5,230’ – 5,250’; 5,255’ – 5,260’; 5,280’ – 5,289’; 5,320’ – 5,323’
    d. *Sand 6*
        i. 5,390’ – 5,410’; 5,412’ – 5,415’; 5,444’ – 5,464’; 5,484’ – 5,490’
5. Run injection tubing and packer with 4 ½” x 7” casing liner to isolate perforations at 4,306’- 4,330’; 4,354’ – 4,374’. See proposed wellbore diagram.
6. Set injection packer at approx. 4,860’.
7. Pressure test 2 7/8” x 7” annulus (communicated from surface to injection packer). See proposed wellbore diagram.
8. Install wellhead assembly.
9. Perform Mechanical Integrity Test (MIT).
10. Perform Step-Rate tests (SRT).
11. RD workover rig. Move off location.

Attachment M - Proposed Injection Wellbore Diagram



Attachment Q-1 Proposed Post-Injection Plug and Abandon Wellbore Diagram



Attachment Q-2 Proposed Plugging and Abandonment

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Snake River Oil and Gas, LLC,
117 East Calhoun St., Magnolia, AR 71753

Permit or EPA ID Number	API Number	Full Well Name
ID2D001-A	11-075-20023	DJS Properties #2-14

State	County
Idaho	Payette

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location

NE 1/4 of NW 1/4 of Section 14 Township 8N Range 4W

95 ft. from (N/S) N Line of quarter section
2315 ft. from (E/W) W Line of quarter section.

Latitude 44.038666 (NAD83)
Longitude -116.783310 (NAD83)

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I ☑ Class II ☐ Class III ☐ Class V	☑ Notice Prior to Work Date Expected to Commence: Injection Permit Proposal ☐ Report After Work Date Work Ended: N/A	☐ Well Rework ☑ Plugging and Abandonment ☐ Conversion to a Non-Injection Well

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

1. MIRU electric wireline unit and cement unit.
2. Bleed off any gas accumulation in tubing or on backside. Fill casing with water as necessary.
3. Establish injection rate into perforations with water down tubing.
4. Mix and pump approx 150 sks cement down tubing into perforations, spot cement plug from 5,490' - 4,870' with 114 sks cement **(Plug #1 5,490' - 4,870').**
5. Set CIBP inside tubing at 4,850' and pressure test same **(Plug #2 4,850').**
6. Perforate tubing at 4,840'.
7. Mix 814 sks cement and circulate in cement plug from 4,840' to 6'. Cement to be left inside tubing and the tubing / casing annulus from 4,840' - 6' **(Plug #3 4,840' - 6').**
8. RD electric wireline unit and cement unit. Wait on cement for 24 hrs.
9. Move in backhoe. Nipple down 2 9/16" wellhead. Dig out bell hole 8' below surface. RU welder.
10. Cut windows on 14" conductor and 9 5/8" casing at 6'.
11. Make primary cut on 9 5/8" casing, 7" casing, and 2 7/8" tubing. Remove casing head and tubing head, along with the cut pieces of casing and tubing. Cut 14" conductor at 6' and remove same. Make final cuts flush on all strings.
12. Weld on 14" steel closure plate. Weld API#, date, and location into plate. Backfill bell hole. Restore location. See attached proposed wellbore schematic, illustrating proposed plugged well condition. Note: All depths are based on the measurements from the drilling rig kelly busing, as directed by the Schlumberger Platform Express - Triple Combo Open Hole Log dated 9/18/14.

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR § 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Richard Brown, Manager	Richard Brown	1-6-2021

EPA Form 7520-19 (Rev. 4-19)

Attachment Q-3 Proposed Plugging and Abandonment cost estimate

Thursday, June 25, 2020

To: Snake River Oil and Gas
117 E Calhoun
Magnolia AR 70753

Re: DJS 2-14 Plug

Below is an estimated cost and procedure summary for plugging and abandoning the DJS 2-14 disposal well based on the provided proposed P&A Wellbore Schematic. The estimated cost included is based on past well abandonments done without a rig in the Willow Field that is located in Payette County Idaho.

Procedure Summary:

1. MIRU wireline unit and cement unit.
2. Squeeze perfs and spot cement plug from 5,490' - 4,870' (Plug #1).
3. Set CIBP inside tubing at 4,850' (Plug #2).
4. Perforate tubing at 4,840'.
5. Mix 814 sks cement and spot long balanced plug from 4,840' - 6'. Cement will be inside tubing and inside tubing / casing annulus (Plug #3).
6. RD Cement unit and wireline unit.
7. Move in backhoe and welder. Nipple down 2 9/16" wellhead and dig bell hole 8' below surface.
8. Cut all casing strings down to 6'. Weld on plate to conductor.
9. Backfill bell hole and dress off same.

Estimated Cost Breakdown:

Cement Crews and Cement	\$26,250.00
E-Log Services	\$32,000.00
Vacuum Trucking Services / Welder	\$8,500.00
Disposal Services / Rentals and Location Clean Up.	\$2,500.00
Estimated Total Cost	\$69,250.00

Please feel free to contact myself directly if you have any questions.

Robert Hatfield
Operations
bhatfield@htisvcs.com
www.htisvcs.com
Office 208.459.9990 | Cell 307.371.4571

Attachment III

UIC Permit Application Attachment H-1 (revised 4/26/2021)

H-1 Calculation of Confined Injection Zone Capacity

Calculation of Confined Injection Zone Capacity

DJS Properties #2-14 Injection Zone

Calculation of Reservoir Volumes:

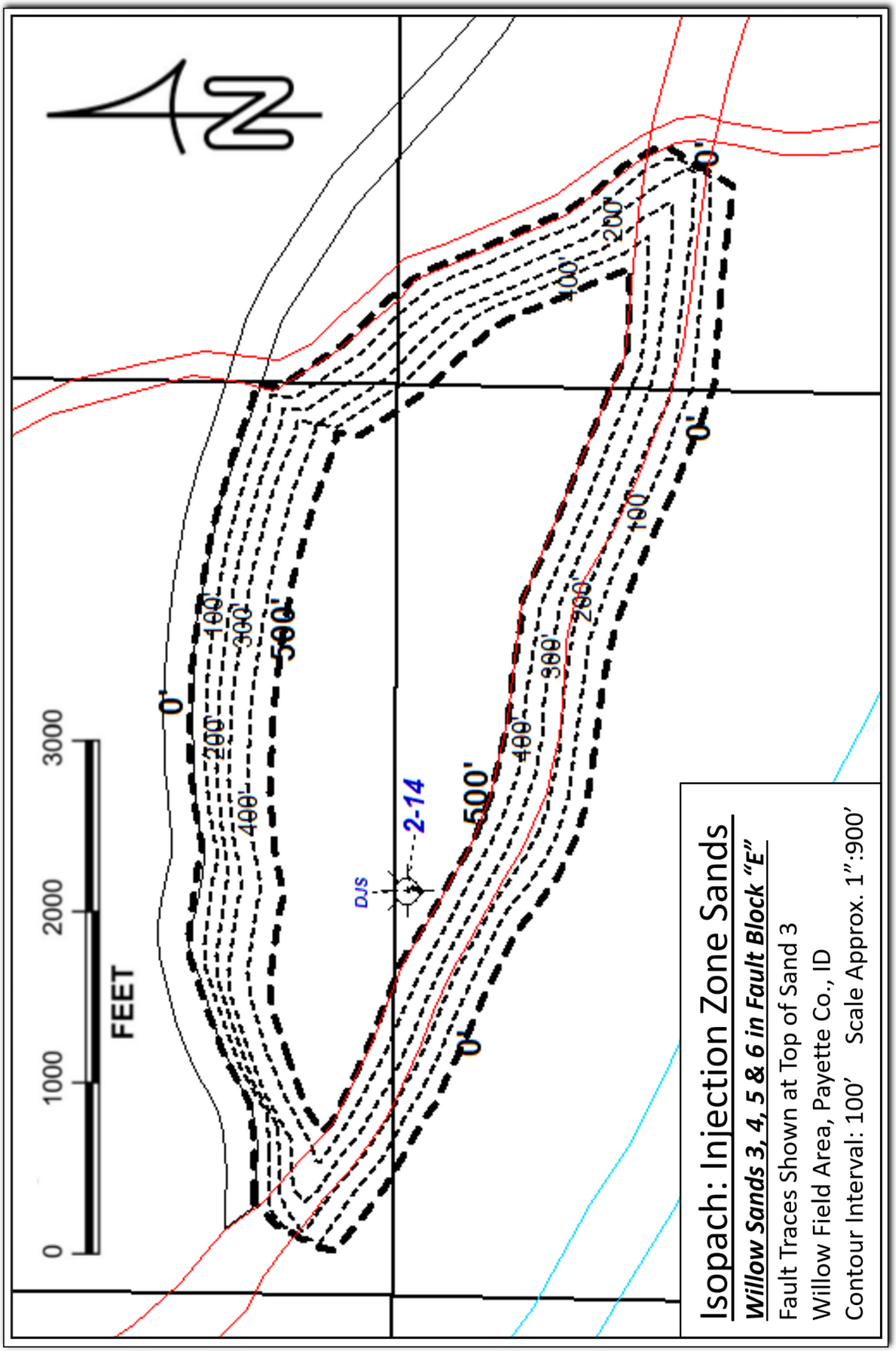
Porosity	0.23	fraction	from well log
Sw	0.80	fraction	water saturation - evidence of gas in swab testing and water analysis
Sg	0.20	fraction	gas saturation - evidence of gas in zone from swab testing - residual gas
Gross Volume	94,700	acre-ft	from planimetry calculations below
Net/Gross Ratio	0.90	fraction	from well logs
Pore Volume	19,603	acre-ft	

Reservoir Isopach Area Planimeter Readings:

CONTOUR LINE VALUE	AREA > (acres)	RATIO OF AREAS	DELTA CONTOUR (ft)	DELTA VOLUME (acre-ft)	
0	269.00				
100	234.00	0.8699	100	25,150.0	
200	205.00	0.8761	100	21,950.0	
300	173.00	0.8439	100	18,900.0	
400	144.00	0.8324	100	15,850.0	
500	113.00	0.7847	100	12,850.0	
		TOTAL ==>		94,700.0	acre-ft - gross bulk reservoir volume

Injection Zone Capacity

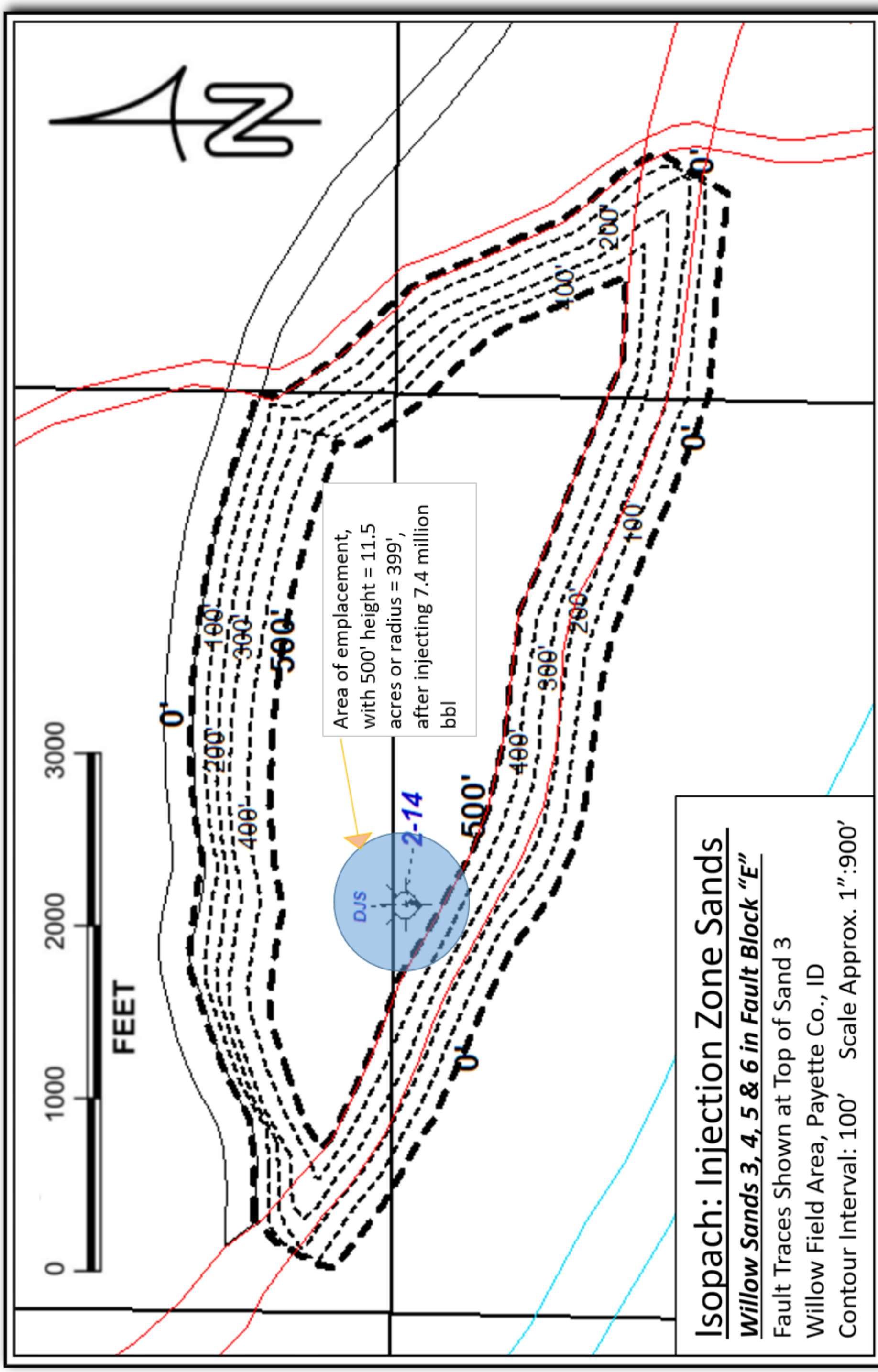
Item	**Value**	**Units**	**Comments - notes**
Datum Depth:	5150	ft, BGL	average depth of injection zone
Average Temperature	251	deg F	ML Investments 1-3 production log
Initial Pressure:	2276	psi	8.6 ppg equivalent pore pressure at datum depth
Fracture Pressure:	3214	psi	12 ppg equivalent pore pressure at datum depth
Maximum Allowable Pressure	2892	psi	90% of fracture pressure
Maximum Pressure Increase (dP)	616	psi	maximum allowable pressure less initial pressure
Average Pressure	2584	psi	average of initial pressure and maximum allowable pressure
Water Salinity	750	ppm Cl	estimated average
Water Compressibility	3.48E-06	1/psi	Osif's Correlation
Gas Compressibility	3.87E-04	1/psi	Meehan et al, Gas gravity = 0.65 from ML Investments 1-10 Well
Rock pore volume compressibility	3.50E-06	1/PSI	Hall's Correlation
Reservoir Water Volume Initial	15,682	acre-ft	Pore Volume * Sw
Reservoir Water Volume Initial	121,663,439	RBbls	Pore Volume * Sw
Reservoir Water Volume Compression	261,022	RBbls	dP * water compressibility* initial water volume
Reservoir Gas Space Volume Initial	3,921	acre-ft	Pore Volume * Sg
Reservoir Gas Space Volume Initial	30,415,860	RBbls	Pore Volume * Sg
Gas Pore Space Compression	7,250,191	RBbls	dP * gas compressibility * initial gas volume
Pore Space Volume Increase	262,281	Rbbls	dP * pore space compressibility
Total Pore Space volume increase	7,773,494	RBbls	sum of water, gas, and pore space compression
Bw (water formation volume factor):	1.055	RBbl/STBbl	McCain's Correlation
Total Stock Tank Barrels Capacity	**7,368,241**	**STBbls**	adjust to surface conditions by dividing by water formation volume factor (Bw)


Isopach: Injection Zone Sands
Willow Sands 3, 4, 5 & 6 in Fault Block "E"
Fault Traces Shown at Top of Sand 3
Willow Field Area, Payette Co., ID
Contour Interval: 100'   Scale Approx. 1":900'
FEET
0
1000
2000
3000
2-14
DJS
0'
100'
200'
300'
400'
500'

Area of Emplacement (AOE) Resulting from Calculated Confined Injection Zone Capacity

The Area Of Emplacement, as defined here is the portion of the injection reservoir that is occupied by injectate, when viewing the reservoir from a top-down vertical view. As produced water is injected into the pore space in the reservoir, mobile reservoir fluids are assumed to be displaced by the injectate. For this illustration, it is assumed that the displacement is uniform and 100% efficient, providing a simple solution for determination based on the final geometrical shape of the emplacement. In this case, since the gas saturation of 20% is assumed to be residual and immobile, the gas saturation serves to reduce the available pore space available for emplacement. The area of emplacement is calculated and shown below based on a simple volumetric method, with no consideration of compressibilities, and assuming a homogenous reservoir of uniform porosity and permeability. Note that the effect of ignoring compressibilities causes the area calculated to be slightly larger than actual. Each of the gas, water and matrix compressibilities would create a smaller area of emplacement than is shown here. The assumption made is that the AOE will conform to a cylinder with the axis about the wellbore, appearing as a circle in map view. The vertical height of the emplacement is simplified by utilizing the isopach thickness seen in the DJS 2-14 well. For this illustration, the circle is centered over the well. Note that southwestern portion of the circle impinges on the isopach wedge below 500' thickness. No effort was made to account for this, since the main point of this calculation and display is to illustrate the relative areas of the emplacement versus the area of the isopach. As shown below the area of emplacement is approximately 11.5 acres versus the total reservoir area of 269 acres. Note that this AOE is for a total injected volume of approximately 7.36 MMBW.

Area of Implacement Calculation:			
Injection Volume:			
Simple - Ignoring Pressure Increase and Compressibilities			
Total Volume to Be Injected	7,368,241	STBBLS	from injection zone capacity
Equivalent cubic feet:	41,375,619.45	ft^3	
Thickness of Isopach at DJS 2-14	500.0	feet	
Porosity:	0.23	fraction	
Gas Saturation:	0.20	fraction	
Effective Water Filled Porosity:	0.184	fraction	
Net/Gross factor	0.90	allowance for net/gross	
Net thickness of 100% water	82.8	feet	
Area of Emplacement:			
Square Feet of Emplacement	499,705.55	ft^2	
Acres of Emplacement	11.47	acres	
Equivalent Circular Radius	398.8	ft	
Equivalent Semi Circle Radius	564.0	ft	

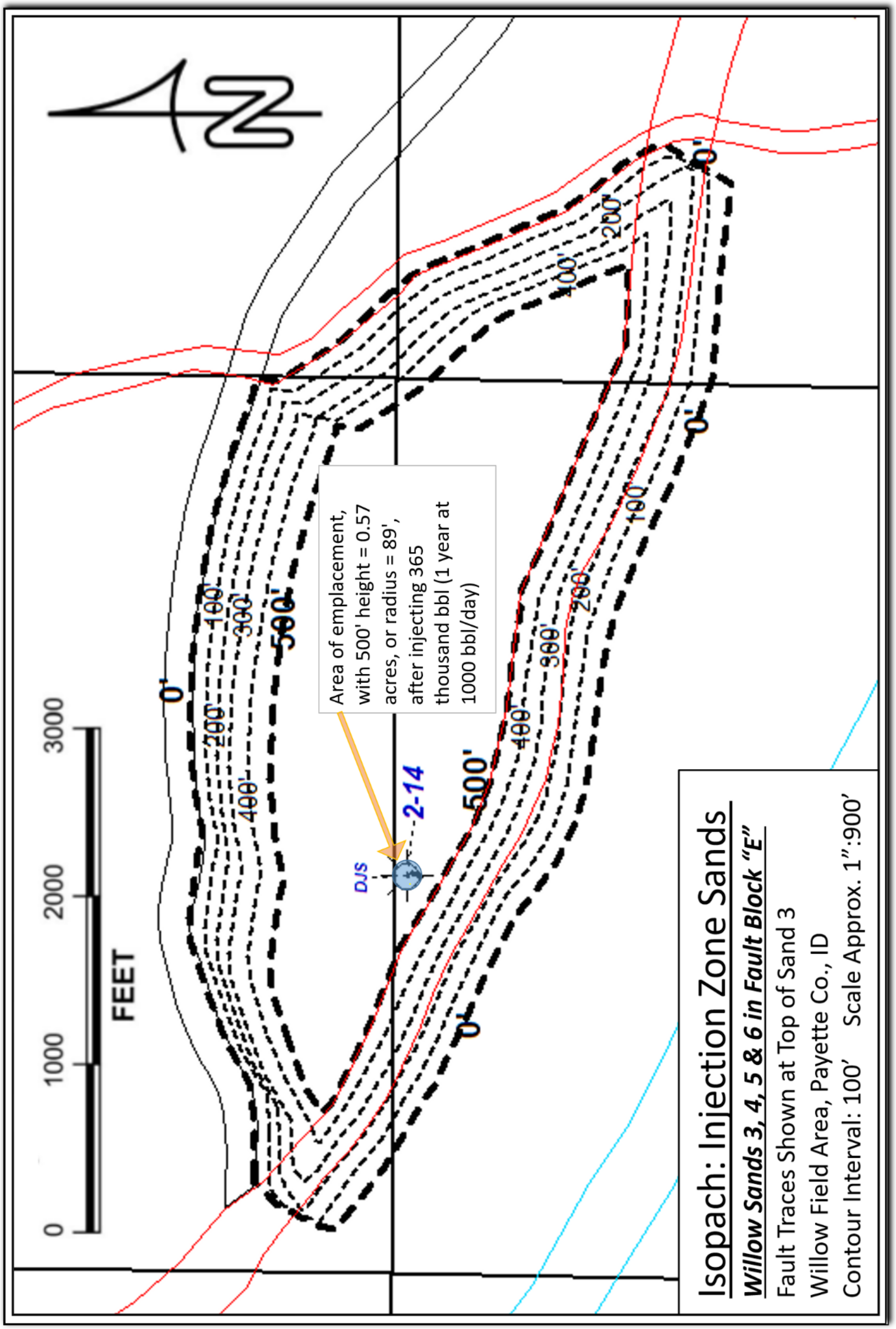


Isopach with Circular Illustration of Area of Emplacement (7,368,000 BBL)

Area of Emplacement (AOE) Resulting from Hypothetical First Year of Injection Service

Shown below is a similar model for the area of emplacement for a single year of injection at the expected average rate of 1000 barrels of water per day. The total injection would be 365,000 bbls of water in a year. The same simplifying assumptions are made as the prior model. The results are an area of 0.57 acres, or a circle with a radius of 89 feet.

Area of Implacement Calculation:			
Injection Volume:			
Simple - Ignoring Pressure Increase and Compressibilities			
Total Volume to Be Injected	365,000	STBBLS	(1 year at 1000 bbl/day)
Equivalent cubic feet:	2,049,621	ft^3	
Thickness of Isopach at DJS 2-14	500	feet	
Porosity:	0.23	fraction	
Gas Saturation:	0.20	fraction	
Effective Water Filled Porosity:	0.184	fraction	
Net/Gross factor	0.90	allowance for net/gross	
Net thickness of 100% water	82.8	feet	
Area of Emplacement:			
Square Feet of Emplacement	24,754	ft^2	
Acres of Emplacement	0.57	acres	
Equivalent Circular Radius	88.8	ft	



Isopach with Circular Illustration of Area of Emplacement (365,000 BBL)

<u>Attachment IV</u>

Letter dated April 5, 2021, from the United State Environmental Protection Agency – Region 10 to Snake River Oil and Gas, LLC, regarding the Aquifer Exemption Request Associated with UIC Permit Application No. ID-2D001-A – Request for a Revised Monitoring Plan

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue, Suite 155
Seattle, WA 98101-3188

WATER
DIVISION

April 5, 2021

DELIVERED BY ELECTRONIC-MAIL

Mr. Richard Brown, Manager
Snake River Oil and Gas, LLC
117 East Calhoun – P.O. Box 500
Magnolia, Arkansas 71753

Re: Underground Injection Control (UIC) Permit Application No. ID-2D001-A – Request for a Revised Monitoring Plan

Dear Mr. Brown,

The U.S. Environmental Protection Agency Region 10 (EPA) is currently reviewing the permit application submitted by Snake River Oil and Gas, LLC (SROG) for the conversion and use of DJS 2-14 as a Class II Disposal well. Based on review of the application and all supplemental materials, EPA is concerned that the current monitoring plan does not adequately ensure protection of Underground Sources of Drinking Water (USDWs) based on the risk of possible fluid migration outside of the injection zone. To ensure continued protection of USDWs, EPA is requesting that SROG submit a revised monitoring plan. If SROG is unable to address this concern, EPA may not be able to issue a permit for this injection well.

Injection of fluids into a Class II well cannot cause the movement of fluids into USDWs. Pursuant to 40 CFR §146.23(a)(1), "…in no case shall injection pressure cause the movement of injection or formation fluids into an underground source of drinking water." SROG has described geologic barriers that would potentially prevent movement of fluids outside of Block E of the Willow Sands, the portion identified for exemption from USDW status pursuant to 40 CFR §146.4. Since the portions of the Willow Sands outside of Block E appear to meet the definition of a USDW, SROG must demonstrate that the proposed injection into Block E will not result in the movement of fluids across fault boundaries and into a neighboring USDW.

To date, SROG has submitted information supporting the notion that the faults separating Block E from the surrounding Willow Sands are sealing. SROG has also conducted a fault-slip potential analysis, which indicated that the pressure needed to activate nearby faults was greater than the proposed maximum increase of reservoir pressure. While it appears that faults across the Willow Field demonstrate sealing behavior, it has not been shown that the specific faults creating Block E will be entirely sealing along their lengths for the life of the proposed injection project. The monitoring program provided in Attachment P of the application does not sufficiently address this gap in certainty. There are two primary reasons why this is not accomplished:

First, the current monitoring program is insufficient because it does not propose a method for evaluating the confinement of the nearest faults (i.e., the southwestern and northern faults) prior to the start of injection. While the evidence submitted to date indicates that these nearby faults are likely sealing, EPA has not received a plan for evaluating these faults prior to injection. Due to the proximity of DJS 2-14 and Block A and Block B, it is important that possible fluid communication is investigated prior to injection.

Second, the current monitoring plan does not describe how fluid movement would be monitored during the life of the well. SROG's current monitoring plan states that pressures will be monitored in offset wells to ensure they fall within "normal operating ranges," and to stop injection operations immediately once "abnormalities" are noted. This plan is insufficient because it is not sufficiently descriptive. It does not define what would be considered abnormalities outside of normal operating ranges, nor does it explain how these abnormalities would relate to fluid movement in Block E. It is also unclear what effect ongoing fluid production from Blocks A and B would have on downhole monitoring, or how the distance between these existing wells and DJS 2-14 would impact detection of movement out of Block E. A plan that includes monitoring of bottomhole pressures needs to explain how that monitoring would identify movement across the specific fault boundaries forming Block E.

A resubmitted plan should be site specific and may incorporate different techniques, such as modeling, testing, and/or passive monitoring. In some cases, pressure fall-off testing and analysis can be used to identify barriers to flow based on pressure transient responses. The results of fall-off testing can also be used to develop anticipated pressure build-up calculations that could be compared to actual bottomhole pressures after injection commences. Another possible element of a monitoring plan could be measurement of fluid levels for nearby producing wells identify hydraulic communication with Block E, though this would need to address fluid balance and distance concerns discussed above. Installation of pressure monitoring wells could also be a way to identify flow and no-flow conditions across a fault, although this method creates the risk of fluid movement to shallower USDWs that should be addressed. These suggestions should not be taken as an endorsement for conditions that would necessitate approval, nor do they represent the universe of possible techniques that could be used. We encourage early and frequent communication to ensure your plan will demonstrate a protection of USDWs.

Please contact Evan Osborne at osborne.evan@epa.gov or (206) 553-1747 if you have any questions related to this request.

Sincerely,

KAREN BURGESS

Digitally signed by KAREN BURGESS
Date: 2021.04.05 17:21:29 -07'00'

Karen Burgess, Manager
Groundwater and Drinking Water Section